PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

January 25, 2005

Agenda ID #4266
Ratesetting

TO: PARTIES OF RECORD IN APPLICATION 04-01-009

RE: NOTICE OF AVAILABILITY OF PROPOSED DECISION IN INTERIM OPINION

Consistent with Rule 2.3(b) of the Commission's Rules of Practice and Procedure, I am issuing this Notice of Availability of the above-referenced proposed decision. The proposed decision was issued by Administrative Law Judge (ALJ) O'Donnell on January 25, 2005. An Internet link to this document was sent via e-mail to all the parties on the service list who provided an e-mail address to the Commission. An electronic copy of this document can be viewed and downloaded at the Commission's Website (www.cpuc.ca.gov).

Any recipient of this Notice of Availability who is not receiving service by electronic mail in this proceeding may request a paper copy of this document from the Commission's Central Files Office, at (415) 703-2045; e-mail cen@cpuc.ca.gov.

This is the proposed decision of ALJ O'Donnell, previously designated as the principal hearing officer in this proceeding. It will not appear on the Commission's agenda for at least 30 days after the date it is mailed. This matter was categorized as ratesetting and is subject to Pub. Util. Code § 1701.3(c). Pursuant to Resolution ALJ-180, a Ratesetting Deliberative Meeting (RDM) to consider this matter may be held upon the request of any Commissioner. If that occurs, the Commission will prepare and mail an agenda for the RDM 10 days before hand. When an RDM is held, there is a related ex parte communications prohibition period.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision as provided in Article 19 of the Commission's "Rules of Practice and Procedure." These rules are accessible on the Commission's website at http://www.cpuc.ca.gov. Pursuant to Rule 77.3 opening comments shall not exceed 15 pages.

Consistent with the service procedures in this proceeding, parties should send comments in electronic form to those appearances and the state service list that provided an electronic mail address to the Commission, including ALJ O'Donnell at jpo@cpuc.ca.gov. Service by U.S. mail is optional, except that hard copies should be served separately on ALJ O'Donnell, and for that purpose I suggest hand delivery, overnight mail or other expeditious methods of service. In addition, if there is no electronic address available, the electronic mail is returned to the sender, or the recipient informs the sender of an inability to open the document, the sender shall immediately arrange for alternate service (regular U.S. mail shall be the default, unless another means – such as overnight delivery is mutually agreed upon). The current service list for this proceeding is available on the Commission's Web page, www.cpuc.ca.gov.

/s/ ANGELA K. MINKIN
Angela K. Minkin, Chief
Administrative Law Judge

ANG:sid

Attachment

Decision **PROPOSED DECISION OF ALJ O'DONNELL (Mailed 1/25/2005)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application Pacific Gas and Electric Company (U 39 E) for Authority to Increase Revenue Requirements to Recover the Costs to Replace Steam Generators in Units 1 and 2 of the Diablo Canyon Power Plant.	Application 04-01-009 (Filed January 9, 2004)

Richard W. Raushenbush, Jennifer K. Post, and Sylvia D. Gardner, Attorneys at Law, for Pacific Gas and Electric Company, applicant.

Paul Angelopulo, Attorney at Law, for the Office of Ratepayer Advocates; Morgan Rafferty, , Attorney at Law, for San Luis Obispo Mothers for Peace, Greenpeace, Sierra Club, Public Citizen, and Environment California; Matthew Freedman, Attorney at Law, for The Utility Reform Network; James Weil, for the Aglet Consumer Alliance; Alcantar & Kahl, LLP, by Michael Alcantar, Attorney at Law, for the Cogeneration Association of California; Ellison, Schneider & Harris, LLP, by Andrew B. Brown, and Douglas K. Kerner, Attorneys at Law, for the Independent Energy Producers Association; Daniel W. Douglass, Attorney at Law, for the Western Power Trading Forum; Adams, Broadwell, Joseph & Cardozo, by Marc Joseph, Attorney at Law, for the Coalition of California Utility Employees; Christopher J. Mayer, Attorney at Law, and Scott T. Steffen, for the Modesto Irrigation District; Amy Peters and James F. Walsh, for San Diego Gas and Electric Company; James Ross, Attorney at Law, for Midway Sunset Cogeneration Company; Carol A. Schmid-Frazee, Attorney at Law, for Southern California Edison Company; Alcantar & Kahl, LLP , by Nora Sheriff, Attorney at Law, for the Energy Producers and Users Coalition; Karen Tarranova, Attorney at

Law, for the Sargent Canyon Cogeneration Company;
interested parties.

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INTERIM OPINION

I. Summary

By this interim order, we present our preliminary findings as to the cost-effectiveness of the steam generator replacement program (SGRP) proposed by Pacific Gas and Electric Company (PG&E) for Diablo Canyon Power Plant Units 1 & 2 (Diablo), and related matters. The review of the SGRP pursuant to the California Environmental Quality Act (CEQA) is currently in progress. We will issue a final decision on the SGRP only after the CEQA review is complete, considering the results thereof.

Based on our analysis of the SGRP as discussed herein, our preliminary determinations are:

- The SGRP is cost-effective.
- $706 million, as adjusted for actual inflation and cost of capital, is a reasonable estimate of the SGRP cost.[1]
- We do not intend to conduct an after-the-fact reasonableness review if the SGRP cost does not exceed $706 million, however we are not precluded from doing so.
- If the SGRP cost exceeds $706 million, or the Commission later finds that it has reason to believe the costs may be unreasonable regardless of the amount, the entire SGRP cost will be subject to a reasonableness review.

[1] All references to capital costs are in 2003 dollars unless otherwise specified. All references to PG&E's $706 million estimated SGRP cost are as adjusted for actual inflation and cost of capital.

- The maximum allowable SGRP cost (cap) is $815 million as adjusted for actual inflation and cost of capital.[2] PG&E will not be allowed to recover SGRP costs in excess of this amount.

- We intend to allow PG&E to record in the Utility Generation Balancing Account (UGBA) the revenue requirement associated with plant additions up to the cap as of the date of operation of each unit.[3]

- We intend to allow PG&E to include the revenue requirement associated with each unit in rates, up to $380 million for Unit 1 and $326 million for Unit 2 on January 1 of the year following commercial operation of each unit; subject to refund. PG&E will be required to file an advice letter to request authority to implement the above rate increase for each unit. The rate increase shall not take effect until and unless the advice letter is approved by the Commission.

- After completion of the SGRP, PG&E will be required to file an application for inclusion of the costs thereof permanently in rates, regardless of whether the costs exceed $706 million. If a reasonableness review is performed, it will be done in connection with the application.

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[2] The $815 million cap will be adjusted for actual inflation and cost of capital by the same percentage as the $706 million amount. All references to the cap are as adjusted for actual inflation and cost of capital.

[3] The $815 million cap is a total SGRP cost cap. It is not divided into a specific amount for each unit, and only applies to the SGRP as a whole. Therefore, if the cap is reached, it will likely be after the first unit is completed.

Regarding the reasonableness review and ratemaking treatment, the above determinations are our preliminary intentions at this time. However, the Commission retains the discretion to require a reasonableness review, or to specify a different ratemaking treatment. In addition, the Commission retains the discretion to determine the appropriate ratemaking treatment, including the possibility of a reasonableness review of costs incurred, if the SGRP is cancelled for any reason.

By this opinion, we do not approve or disapprove the SGRP, guarantee or approve the recovery of any expenditures related thereto, or prejudge the outcome of the Commission's environmental review. We do, however, affirm the rulings of the assigned administrative law judge (ALJ) as discussed herein.

II. Background

Diablo is a nuclear power plant consisting of two units, Unit 1 and Unit 2, with a capacity of approximately 2,260 megawatts (MW).[4] It generates approximately 17,000 gigawatt-hours of electricity each year, or about 20% of the electric energy delivered by PG&E in its service territory. It is located on the California coast 7.5 miles north of Avila Beach, in San Luis Obispo County. Each of the two units has four steam generators manufactured by Westinghouse Electric Corporation (Westinghouse). In each steam generator, the heat from water circulated through the reactor is used to turn another stream of water into steam that is used to run the turbines that drive the electric generators.

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[4] This includes a 40 MW increase in capacity due to the low-pressure turbine rotor replacement scheduled for 2005-6.

Diablo is currently licensed by the Nuclear Regulatory Commission (NRC) to operate until 2024 (Unit 1) and 2025 (Unit 2).[5] PG&E estimates that Diablo will likely be required to shut down because of the degradation of the steam generators in 2013 (Unit 2) and 2014 (Unit 1). As a result, PG&E is requesting approval in this application for its SGRP.

Hearings were held from September 20 through October 1, 2004. The application was submitted upon the receipt of reply briefs on November 9, 2004. The proceeding remains open to consider the results of the CEQA review.

III. PG&E's Request

In this application, PG&E requests that the Commission approve the replacement of Diablo's eight steam generators. Specifically, PG&E requests that the Commission:

1. Determine that $706 million is a reasonable and prudent cost for replacement of the steam generators;[6]

2. Authorize PG&E to recover the costs, up to $706 million, without further reasonableness review;

3. Authorize PG&E to seek recovery in rates of any amounts above $706 million, subject to an after-the-fact reasonableness review of the additional costs;

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[5] This assumes recapture of the approximately three years of operating license for Unit 1 consumed prior to fuel loading and full-power operation. PG&E forecasts an 80% probability of NRC approval of its request for recapture.

[6] The $706 million figure includes $380 million for Unit 1, and $326 million for Unit 2.

4. Authorize PG&E to record the revenue requirement associated with SGRP plant additions for each unit equal to or less than $706 million in the UGBA as of the date of operation of each unit;

5. Authorize PG&E to include the revenue requirement associated with each unit in rates on January 1 of the year following commercial operation of each unit;

6. Authorize PG&E to record in the UGBA the revenue requirement, if any, associated with plant additions above $706 million ($380 million for Unit 1 and $326 million for Unit 2) as of the date of operation of each unit. PG&E would be at risk for these revenue requirements, and would only be allowed to include them in rates if such costs were ultimately found to be reasonable and prudent by the Commission; and

7. Approve modifications to the UGBA to allow for the recording of the above revenue requirements.

IV. Need for the SGRP

No party disputes PG&E's claim that the steam generators must be replaced if Diablo is to stay in operation through the end of its license lives. However, the parties differ on when the units will have to shut down if the SGRP is not performed.

PG&E represents that the least-cost and least-risk timing of the replacement is 2008 for Unit 2, and 2009 for Unit 3. PG&E states that the timing is important because delay would: (1) increase the risk of a failure resulting in a forced outage before replacement; (2) result in increased project cost escalation, and costs for additional inspection, repair and maintenance of the existing steam generators; and (3) cause coordination problems with the steam generator replacement projects for the San Onofre Nuclear Generating Station (SONGS) scheduled by Southern California Edison Company (SCE) for 2009. PG&E represents that a one fuel cycle delay would cost an additional $33 million and a two cycle delay would cost an additional $67 million.

The Commission's Office of Ratepayer Advocates (ORA) recommends that the SGRP be delayed until 2009-2010. It says that the delay would cost only $33 million, and would allow PG&E and the Commission to determine whether steam generator degradation is occurring at a faster or slower rate than predicted. ORA also represents that if degradation occurs at a slower rate, "PG&E will be able to get a little extra use out of the existing steam generators," and determine the effectiveness of sleeving degraded tubes to allow them to be returned to service.

The SGRP is needed if Diablo is to continue operating throughout the remainder if its license lives. If the SGRP is to go forward, ORA's recommended delay would result in more monies being spent on the original steam generators, without a corresponding decrease in the cost of the SGRP. In addition, there is an increased risk of a forced outage as the steam generators degrade. As a result, if the SGRP is approved, it should be performed according to PG&E's proposed schedule.

The Utility Reform Network (TURN) recommends that if the SGRP is approved for Diablo, and also approved for SONGS in Application (A.) 04-02-026, the Commission should have a consolidated phase of both proceedings to determine whether the risks of capacity shortages, when compared to the costs of project delays, warrant a change in the steam generator replacement schedule for one or both facilities. Since we have reached no decision in A.04-02-026, it is premature to consider TURN’s recommendation at this time, and we will not do so.

TURN represents that the current statutory prohibition on customers leaving bundled service will expire before 2014, and that the lifting of this prohibition could lead to the reduction of bundled loads served by PG&E. In other words, some customers could purchase power from the market rather than PG&E. TURN states that this could lead to a reduction in PG&E’s retail load, which could result in a reduced need for PG&E to procure replacement capacity in the event that Diablo shuts down. TURN says that if the SGRP is performed, Diablo power would then have to be sold on the market. TURN recommends that PG&E should be ordered to change its model inputs accordingly.

It is possible that the end of the current statutory prohibition on customers leaving bundled service could lead to the reduction of bundled loads served by PG&E. However, the record does not indicate the probability of this happening, when it would occur, or the amount of the reduction. In addition, the load would still have to be served. As a result, it does not follow that the demand for electricity would be reduced, or that Diablo would not be needed. Therefore, we see no reason to adjust our cost-effectiveness analysis for this possibility. Even if we were inclined to do so, we have no basis for determining what adjustment to make.

V. PG&E’s Cost-Effectiveness Model

In this proceeding, PG&E conducted its cost-effectiveness modeling using a Monte Carlo simulation model. The model has over 100 input variables. Each variable has a low, base and high value associated with it. The low value has a 10% probability of the actual value being below it. The base value has a 50% probability of the actual value being below it. The high value has a 90%

probability of the actual value being below it. The variables and their probabilities were estimated by PG&E or its consultants. For each run, the model randomly picks a low, base, or high value for each variable, and compares the cost of the SGRP to the no project alternative. The model then performs successive runs until the mean simulation error was below $10 million.[7] For PG&E's cost-effectiveness analysis, the model performed over 9600 runs. The mean of the results of the model runs was then calculated to determine the mean net present value of revenue requirements (NPV).[8]

PG&E's analysis yields an NPV of the SGRP of $1.2 billion. This means that there is an 80% probability that the NPV will be between $173 million and $2.44 billion, with a 10% probability that the NPV will be below $173 million and a 10% probability that it will be above $2.44 billion. It also means that there is a 95% probability that the SGRP will be cost-effective, and a 5% probability that it will not be cost-effective.

San Luis Obispo Mothers for Peace, Greenpeace, Sierra Club, Public Citizen, and Environment California (collectively, MFP) contend that PG&E's model has never been relied upon by a regulatory agency for decision making. MFP also states that PG&E's model ignores correlations between variables such as between capital costs, O&M costs, and capacity factor.

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[7] A mean simulation error of $10 million means that if the analysis were run again, the result would be within $10 million of the reported $1.2 billion cost savings in approximately two-thirds of the simulations.

[8] NPV refers to the net present value to ratepayers of the revenue requirements resulting from the estimated costs and benefits.

As to correlations between variables, it is reasonable to assume that capital costs and O&M costs are related to Diablo's performance as measured by its capacity factors. This is because capital and O&M costs are incurred in order to keep Diablo in operation. It would seem reasonable, for example, to assume that a low capacity factor or an outage could result in increased capital or O&M expenditures to correct any plant problems that led to the low capacity factor or outage. In this case, a low capacity factor would be associated with increased capital or O&M expenditures. However, increased capital additions or O&M could be implemented to avoid a decrease in the capacity factor or an outage, in which case increased capital additions or O&M would be associated with no change in capacity factor. In addition, there are other factors which may influence capacity factors such as regulatory requirements and plant design. For these reasons, we do not find it unreasonable that the model fails to incorporate a mathematical formula directly linking capital costs, O&M costs and capacity factors. We also note that MFP has not indicated what the mathematical relationships between these or other variables should be.

PG&E provided an explanation of its model, and the assumptions it used. As discussed later in this decision, ORA and TURN's models yield results generally similar PG&E's model when similar inputs are used. This tends to indicate that PG&E's model's results are not unreasonable. Therefore, we conclude that PG&E's Monte Carlo simulation model is appropriate for use in this proceeding. We will now address the parties' concerns regarding various model inputs.

VI. Model Inputs

A. Cost of the SGRP

PG&E represents that the SGRP will cost $706 million.[9] PG&E originally estimated that it would cost $182 million for the contract to fabricate and deliver the eight steam generators (procurement contract), $339 million for the contract to install them (installation contract), and $185 million for materials and services to be provided by PG&E (owner's costs), for a total of $706 million. PG&E has since signed a procurement contract. PG&E reduced the contingency amount for the installation contract to offset the increased procurement contract costs. As a result, the updated estimate is $209.3 for the procurement contract, $311.7 million for the installation contract, and $185 million for owner's costs, for a total of $706 million.

ORA states that PG&E used its test year 2003 authorized cost of capital of 9.24% in calculating its allowance for funds used during construction (AFUDC) rate. ORA points out that PG&E has requested a lower cost of capital in A.04-05-023 and, therefore, concludes that that PG&E's AFUDC rate is too high. ORA also recommends the use of an 11% contingency amount for owner's costs, rather than PG&E's 20% contingency amount. ORA states that these adjustments would result in lower project costs. ORA also notes the higher than estimated costs for the procurement contract, and recommends that PG&E's $706 million estimate should not be preapproved.

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[9] This does not include $50 million in decommissioning costs due to the SGRP. However, these costs were included in the cost-benefit calculation.

TURN states that PG&E used a benchmarking study (a comparison of costs at other plants) to demonstrate the reasonableness of its estimated cost for the SGRP. TURN represents that the benchmarking study did not properly adjust the costs of the comparison plants to reflect the differences with Diablo. Therefore, it recommends that the Commission not rely on the benchmarking study in reviewing PG&E's SGRP cost estimate. TURN also states that, as a result of PG&E's use of the benchmarking study, the procurement contract with Westinghouse may be priced excessively high. TURN contends that the Commission should review the results of all bids received for the procurement and installation contracts to determine the reasonableness of PG&E's cost estimates.

MFP believes, based on the increase in the procurement contract cost, that the cost of the SGRP will be higher than PG&E's forecast. Therefore, it recommends that PG&E be required to rerun its model with the SGRP cost increased by 10-20%.

ORA believes that PG&E's $706 million estimate may be too high. MFP and TURN think a higher cost should be considered in the cost-effectiveness analysis. ORA, TURN, MFP, and Aglet oppose its use as an assumed reasonable cost, and no party has suggested a different estimate. Therefore, we believe that $706 million is a reasonable cost estimate for use as a base case in our cost-effectiveness analysis. However, a higher cost is possible, and should be considered.

The $209 million procurement contract cost is approximately 15% more than PG&E's estimate. The installation contract will be a time and materials contract rather than a fixed-cost contract. This means that installation contract costs could be more than PG&E estimates if the bid it ultimately adopts is higher than its estimate, more time and/or materials are necessary to complete the project, or both. In addition, it is reasonable to conclude that the owner's costs will be dependent to some degree on the actual costs incurred pursuant to the installation contract. While we do not know how much the installation contract costs and owner's costs will increase, it is not unreasonable to conclude that they could increase as much as the procurement contract cost. Considering the above possibilities, if PG&E's original estimates of the installation contract cost and owner's costs were to increase by 15%, as was the case with the procurement contract, the total SGRP cost would be $815 million.

PG&E insists that its $706 million estimate is reasonable, even with the higher than expected costs for the procurement contract. Therefore, an argument could be made that this amount should be set as a cap on the SGRP costs. As discussed above, it is possible that the SGRP could cost as much as $815 million. Use of that amount as a cap would provide PG&E with some incentive to control costs, while recognizing that costs could be higher than PG&E's estimate. Given that the $815 million amount would be adjusted for actual inflation and cost of capital, two significant cost drivers, we do not believe that imposition of such a cap would put PG&E unduly at risk. At the same time, such a cap would limit ratepayers' exposure to cost overruns, and help ensure that the SGRP is cost-effective. Therefore, we will adopt $815 million as a cap. We will also consider this amount in our cost-effectiveness analysis.

Regarding ORA's concerns about the AFUDC rate, inclusion of a higher AFUDC rate resulting from a higher cost of capital will result in a higher project cost. This, in turn, would tend to make the SGRP less cost-effective, resulting in a more conservative cost-effectiveness analysis. Therefore, we need not make this adjustment in the cost-effectiveness calculation. In addition, the $706 million estimate and the $815 million cap will be adjusted for actual inflation and cost of capital. Therefore, utilizing PG&E's AFUDC rate in evaluating this application will not adversely affect ratepayers.

B. O&M Costs

PG&E assumed a base level O&M cost of $223 million based on 2001 recorded non-fuel O&M costs adjusted for any major non-recurring O&M projects. PG&E then added specific major O&M projects and costs related to forecast refueling outages it anticipates between 2003 and 2010.[10] PG&E based its 2011 estimate on 2001 recorded non-fuel O&M costs adjusted for any major non-recurring O&M projects. For 2012 through 2024, PG&E escalated the 2011 estimate by 2.5% for inflation, and added in costs related to planned refueling outages.

TURN objects to PG&E's 2010 estimate, and its use as the basis for estimates of future years, because it amounts to about $10 million less than the average recorded costs for 1997 through 2003 in 2003 dollars. TURN states that PG&E's estimate assumes that there will be no unforeseen O&M costs in the future, although given the unexpected surprises experienced in the past, such as the need to replace the reactor vessel heads, such additional costs could occur in the future. TURN also states that PG&E included in its 2003 general rate case an estimate of $45 million in administrative and general (A&G) expenses associated with Diablo. In this application, TURN states that PG&E included no A&G expenses other than pensions and benefits. TURN recommends that, although the exact magnitude of the additional A&G that should be included is uncertain,

[10] Note that PG&E's estimates were prepared in 2003.

an increase is warranted. For the above reasons, TURN recommends that PG&E's O&M estimates for 2011 through 2024 should include an escalation of 1% or 2% over the nominal 2010 value. This would mean a 1% or 2% escalation over and above PG&E's estimates.

Based on TURN's recommendations, MFP recommends that the Commission require PG&E to run its model with a 2% real escalation in the O&M costs, a wider range of values in its sensitivity analysis, and require PG&E to indicate the portion of the A&G costs for Diablo included in its 2003 GRC that will be avoided if the SGRP is not performed.

As explained above, PG&E's calculation of O&M cost for 2011 and after is not based on its 2010 estimate as TURN contends. However, it is not clear from the record that PG&E's estimate of O&M costs is wrong by a specific amount. We find compelling the argument that there could be unexpected O&M costs in the future. PG&E's model escalates the 2011 value for subsequent years at a rate of 2.5%. Therefore, we will raise the escalation rate to 4.5% for the purpose of the cost-effectiveness evaluation.

C. Capital Additions-General

In its cost-effectiveness analysis, PG&E assumed a base level of capital additions, excluding the SGRP, of $24 million based on the average capital additions from 1997-2002. These are annual capital additions that will take place each year until Diablo ceases operation whether the SGRP is approved or not. To the base, PG&E added $259 million in major capital projects, excluding the SGRP, that it believes are necessary to operate Diablo until the end of its license lives if the SGRP is performed, but that would be avoided if the SGRP is not performed. PG&E assumed that all major capital additions necessary to operate Diablo until the end of its license lives, if the SGRP is performed, will be completed by 2015.

That means that the only capital additions in its forecast after 2015 are the base capital additions.

TURN did not take issue with the specific capital projects included by PG&E. However, it states that PG&E's base capital additions amount is not sufficient to cover the unexpected costs that will occur resulting from the ageing of the plant, and possible regulatory requirements. ORA concurs.

Aglet Consumer Alliance (Aglet) states that PG&E's average capital additions for 1988 through 1997 were $87 million.[11] In addition, Aglet states that capital expenditures will likely increase as Diablo ages. Therefore, it states that base capital additions should be increased to $87 million escalated to future years in the same manner as PG&E's estimate.

MFP states that problems related to the aging of Diablo, and the potential problems that can develop in the first few years with newly installed equipment, like the major capital additions forecast by PG&E, could lead to additional capital costs. Therefore, MFP supports the base capital additions figure recommended by Aglet. In addition, MFP states that another $88 million per year should be added because PG&E's estimate of major capital additions, in addition to base capital additions, averages $88 million for 2003-2015.

It is reasonable to assume that there will be plant additions in the future that are not known at present. Additionally, as a plant ages, one would expect to see an increase in plant additions as components are replaced. This should be offset to a large degree by PG&E's forecast of major capital projects. However,

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[11] Aglet states that capital additions declined dramatically from 1996 through 2001, and rose to approximately $16 million in 2002, and 2003.

some degree of uncertainty remains. Therefore, we believe Aglet's proposal has merit. Since PG&E's estimated annual capital additions through 2015 are in excess of the amount Aglet proposes, we will apply Aglet's proposal to the years after 2015 where PG&E's total annual capital additions are the base amount of $24 million.

PG&E's major capital additions are intended to reduce uncertainty to a substantial degree. It does not follow that PG&E's forecast of major capital additions translates to greater uncertainty as MFP appears to imply by its proposal to increase capital additions by an additional $88 million. We believe that the above increase to base capital additions is sufficient to take care of uncertainty. Therefore, we will not adopt MFP's $88 million recommendation.

TURN asserts that PG&E inappropriately excluded $117 million in capital expenditures associated with its low-pressure turbine rotor replacement project from the cost-effectiveness analysis of the SGRP. TURN asserts that, since PG&E has not demonstrated that this project would be needed if the SGRP is not performed, it should be assumed to be avoided if the SGRP is not performed.

PG&E states that the low-pressure turbine rotor replacement project was determined to be a better option than refurbishment. The contract for the project was signed in 2002, is scheduled for completion in 2005-6, and is expected to add 40 MW to Diablo's capacity. PG&E represents that cancellation of the project would result in cancellation costs and, in addition, the low-pressure turbine rotors would have to be refurbished. Therefore, PG&E states that it is inappropriate for inclusion in the cost-effectiveness analysis of the SGRP.

Since the low-pressure turbine rotor replacement project is underway, and will be completed several years before the SGRP, it is not related to the SGRP. In addition, we have no reason to believe that it would be cost-effective to cancel the project at this time, or that it is not needed. Therefore, we will not include the project costs as a cost related to the SGRP.

D. Capital Additions-Security Measures

MFP believes that there is a high probability that the NRC will impose more stringent security requirements on Diablo. It bases this claim on the fact that on September 17, 2004, the United States Court of Appeals for the District of Columbia issued an order that states that the NRC will commence a rulemaking proceeding to consider revisions to the design basis threat that forms the basis for the NRC's security requirements at nuclear power plants. MFP also says that the Government Accountability Office (GAO), in testimony before a House of Representatives Subcommittee, said that the NRC could not assure that commercial nuclear power plants were safe from terrorist attack. MFP says the GAO reported that the Department of Energy is reviewing the security requirements for its nuclear power plants. MFP notes that the current requirements do not include defense against terrorist attacks by airplanes. MFP contends that these additional security requirements will result in increased capital and O&M costs that should be included in the cost-effectiveness evaluation of the SGRP.

MFP provided three scenarios to illustrate its estimates of the increased security costs:

- The first scenario assumes that Diablo stays in operation. MFP estimates that additional security requirements would result in additional capital costs of $314 million spread over the first two years, and $13 million per year thereafter until the reactors are shut down.[12] Annual O&M costs would increase by $54.5 million until the reactors are shut down. After the reactors are shut down, there would be additional capital costs of $51 million over the first five years. The additional annual O&M costs would be $11 million per year after shutdown.[13]

- The second scenario assumes that Diablo is permanently shut down when the requirements are put into effect. It also assumes that a lesser level of enhanced defenses would be put in place only to safeguard the spent fuel. MFP estimates that the additional capital costs would be $143 million spread over the first five years after shutdown, and $2.4 million per year thereafter. The additional annual O&M costs would be $11 million per year after shutdown.

- The third scenario assumes that Diablo continues in operation for three years after initiation of the security requirements, and then is shut down.[14] MFP estimates that the additional capital costs will be $128 million spread over the first two years, and $13 million for the third year.[15] The additional O&M costs would be

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[12] All dollars in MFP's scenarios are 2004 dollars unless otherwise specified.

[13] MFP does not say what the annual O&M costs would be after shutdown, but presumably they would be $11 million as in the second and third scenarios.

[14] This scenario assumes that the enhanced security requirements include more stringent steam generator tube integrity requirements that lead to shut down in three years.

[15] MFP states that the additional capital costs would be $2.4 million for the fourth year, but under this scenario, Diablo only operates for three years after the security enhancements are put into effect. Therefore, we have not included this amount in our analysis of MFP's recommendation.

> $35 million per year for the three years the reactors are operating. After the reactors are shut down, there would be additional capital costs of $51 million over the first five years. The additional annual O&M costs would be $11 million per year after shutdown.

Based on the above, MFP recommends that PG&E be required to rerun its model with the above cost estimates, and perform a sensitivity analysis.

MFP's first scenario corresponds to continued operation more than three years after the enhanced requirements are put into effect. This corresponds to both the case where the SGRP is performed, and to the case where the SGRP is not performed, unless it is known at the time the security requirements are put into effect that neither Diablo unit will continue in operation for more than three years. Given the uncertainty as to when Diablo will shut down if the SGRP is not performed, this appears to be the most likely scenario both with and without the SGRP.

MFP's second scenario has both Diablo units permanently shutting down when the enhanced security requirements are put into effect. Since the replacement energy cost for one unit is substantial, it would likely be cost-effective to implement security requirements even if only one unit has a few years of life remaining. Therefore, this scenario is unlikely.

MFP's third scenario assumes that the NRC would exempt Diablo from some of the new security requirements because it will not continue in operation for more than three years. Without the SGRP, it is uncertain when either of the Diablo units will shut down, therefore, it appears unlikely that the NRC would impose lesser security requirements. Therefore, this scenario is unlikely.

MFP appears to believe that enhanced security requirements will be imposed within the next few years. In that case, it first scenario would apply whether or not the SGRP is performed. The only effect on the cost-effectiveness analysis would be the reduction in the increased O&M from $54.5 million to $11 million due to shutting Diablo down at a later date.

We have no basis in the record for estimating the probability of the occurrence of future increased security requirements or their timing. MFP's assumption that lesser additional security requirements would be imposed if Diablo is shut down at the time of imposition is unlikely. Based on MFP's representations most, if not all, of any new security requirements would be imposed on Diablo with or without the SGRP. In addition, the costs estimated by MFP are illustrative examples rather than estimates based on known requirements. For the above reasons, we will not adopt MFP's cost estimates. However, the possibility of future increased security requirements supports our earlier conclusion that some increase in future capital additions and O&M expenses above the amount forecast by PG&E is appropriate.

E. Capital Additions-Seismic Issues

MFP asserts that additional seismic requirements will be imposed on Diablo. It notes that, in April 2004, PG&E was granted a permit by San Luis Obispo County to construct an independent spent fuel storage installation (ISFSI) for spent nuclear fuel at Diablo. A condition of the permit is that PG&E must update its Long Term Seismic Plan (LTSP) to incorporate data developed since the LTSP was created in 1988. MFP also states its belief that the California Coastal Commission (CCC) will agree that the LTSP should be updated. MFP states that it is unlikely that, if San Luis Obispo County and the CCC require a change in the LTSP for the ISFSI, the NRC will ignore the change.

MFP also states that if the ISFSI is not approved or is delayed, Diablo could be forced to shut down in 2006 because it will not have sufficient storage for its spent fuel. As a result, MFP recommends that PG&E should be required to provide an explanation of the range of uncertainties regarding the storage of spent fuel at Diablo, and the costs of possible seismic upgrades to Diablo as a result of the San Luis Obispo County and CCC actions.

Neither San Luis Obispo County or the CCC have the authority to require a change to Diablo's seismic design criteria. That authority lies with the NRC. If the NRC was to revise the seismic design criteria for Diablo, there would be no effect on the cost-effectiveness analysis unless significant modifications to Diablo are necessary as a result. Therefore, the effect on the cost-effectiveness analysis depends on the probability that modifications would be required, the costs of the modifications, and when such costs would be incurred. MFP has provided no estimate of the probability that Diablo's seismic design criteria will be revised, when the revision will be imposed, whether plant modifications will be necessary as a result, or what the costs of such modifications will be. As a result, there is no basis in the record for assessing the impact on the cost-effectiveness analysis of a possible revision to Diablo's seismic design criteria. However, the possibility of future revisions supports our earlier conclusion that some increase in future capital additions and O&M expenses above the amount forecast by PG&E is appropriate.

As to the ISFSI, it is by no means certain that a forced shutdown will occur in 2006. If it were to occur, the SGRP could be stopped if necessary, and cancellation costs addressed as appropriate. Since such a forced shutdown would occur before the SGRP is to be performed, it would have no effect on the cost-effectiveness analysis of the SGRP. For the above reasons, we will not include it in the cost-effectiveness analysis.

F. Extended Outage

TURN argues that there is a 42% probability of a year-long outage at some time during Diablo's remaining life. This is based on TURN's analysis that showed that 27 nuclear units, out of approximately 105 nuclear units in the United States, have encountered delays of a year or more in restarting. TURN further states that since 1990, 15 nuclear units have experienced outages of between 15 and 32 months, and another six units have experienced outages of between 9 and 12 months. TURN states that PG&E did not include such an outage in its analysis, and recommends that one should be included in the cost-effectiveness analysis for the period after the replacement of the steam generators. MFP supports this recommendation.

PG&E contends that while some nuclear plants mentioned by TURN and MFP have had shutdowns due to equipment problems, in almost all cases, the shutdowns were extended due to NRC concerns over plant management culture, compliance with regulations and design basis concerns. PG&E represents that it has a strong safety culture, has complied with all applicable regulations, and conducted an independent design re-verification prior to commercial operation. Therefore, PG&E states that the probability of an extended outage is small.

TURN's pre-filed testimony shows that it believes there is a 25.2% probability that one Diablo unit will have an outage of one year by 2014. According to TURN, the probability rises to 42.5% by 2024. TURN's analysis does not address the causes of the outages, Diablo's similarity to the plants that experienced the outages, Diablo's vulnerability to such outages, or the degree to which PG&E has taken or plans to take actions to avoid them. The probability of a 12-month outage after the SGRP is completed is dependent to a substantial degree upon PG&E's efforts to maintain and operate Diablo. To the extent that PG&E takes aggressive action to prevent possible problems, the probability of such an outage is reduced. The record does not demonstrate that PG&E has not or will not take such actions. Indeed, the proposed SGRP is an example of such actions. In addition, the record does not demonstrate that PG&E has failed to comply with regulatory requirements for continued operation. Therefore, we have no reason to believe such an outage is likely. However, while the probability appears small, the possibility does exist and supports our earlier conclusion that some increase in future capital additions and O&M expenses above the amount forecast by PG&E is appropriate. Notwithstanding the above discussion, we will include the possibility of a one-year outage of one unit in our cost-effectiveness analysis, in order to test the sensitivity of the SGRP's cost-effectiveness to such an outage.

G. Capacity Factor

PG&E's estimated future capacity factors for Diablo, assuming the SGRP is performed, are 94.67% between refueling outages, and 90.6% including refueling outages. TURN does not object to using this as the base case. However, it recommends that a low case assumption of a 75-85% capacity factor should also be considered.[16] The lower capacity factor would recognize the possibility of unexpected outages due to unforeseen problems or industry-wide technical or regulatory issues including the effect of aging plant components.

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[16] TURN did not specify if the capacity factors it recommends were between or including refueling outages.

MFP recommends that PG&E be ordered to rerun its model using a range of capacity factors that reflect increased outages for O&M due to ageing of Diablo.

The probability of a reduced capacity factor after the SGRP is completed is dependent upon the efforts of PG&E to maintain and operate Diablo. To the extent that PG&E takes aggressive actions to prevent outages and keep Diablo operating at full capacity, the probability of a reduced capacity factor is lessened. The record does not demonstrate that PG&E has not or will not take such actions. Therefore, we have no reason to believe that a lower capacity factor is likely. We note that a reduction in the capacity factor due to an unexpected outage would not likely be a routine event affecting the capacity factor for both units for the entire life of the plant. Therefore, a reduced capacity factor, in the amounts recommended by TURN for the entire life of Diablo after the SGRP, does not appear likely. Notwithstanding the above discussion, we will include lower capacity factors in our analysis of the cost-effectiveness of the SGRP in order to test the sensitivity of the SGRP's cost-effectiveness to reductions in the capacity factor.

H. Replacement Energy Prices

For replacement power costs, PG&E examined three scenarios. The first scenario assumes that 2,260 MW of power is purchased from the market. The second scenario assumes that PG&E constructs 2,200 MW of new combined cycle generation.[17] The third scenario assumes that 10% of the combined cycle generation in the second scenario is replaced by renewable generation (i.e., wind). PG&E's electricity market price estimate in the first scenario utilized

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[17] PG&E assumed that an additional 60 MW would be purchased from the market.

PG&E's natural gas price estimate. PG&E's calculation of new combined cycle generation costs in the second and third scenarios used a 20-year facility life, as well as its natural gas price estimate.

The gas prices forecast by PG&E for this proceeding were its expected annual burner tip gas prices based on the September 5, 2003, New York Mercantile Exchange (NYMEX) closing price of forward contracts.[18] In A.04-04-003, PG&E's 2004 long-term resource plan proceeding (LTRP), it forecast gas prices based on the April 19, 2004 NYMEX closing price. PG&E contends that the prices in its forecast in A.04-04-003 are within the range of prices it used in this proceeding.

TURN notes that the LTRP gas price forecast was based on a more recent NYMEX closing price, resulting in lower forecast electricity prices than those used by PG&E in this proceeding. It recommends that the gas price forecast used in the LTRP should be used in this proceeding.

The fact that the NYMEX closing prices changed between September 5, 2003, and April 19, 2004 demonstrates that gas prices are variable. Neither closing price is necessarily better as a base for estimating gas prices between now and 2025. Therefore, we will utilize both closing prices for forecasting gas prices in our cost-effectiveness evaluation.

TURN represents that the 20-year combined cycle generation facility life used by PG&E is unreasonable. TURN points out that a 30-year life was used by SCE and SDG&E in other applications, and advocates its use in this proceeding. MFP concurs.

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[18] Burner tip prices are the prices of the gas delivered to the power plant.

PG&E represents that it used a combined cycle construction cost estimate prepared by the California Energy Commission (CEC), which used a 20-year life. PG&E also points out that the CEC estimate does not include interconnection or transmission network upgrade costs.

The CEC's construction cost estimate based on a 20-year life does not include interconnection or transmission network upgrade costs. However, a 30-year facility life would be more appropriate for the reasons put forth by TURN. Therefore, we will increase the facility life to 30 years in our cost-effectiveness analysis. Our use of the 30-year facility life in the construction cost estimate is conservative because it does not change the fact that the construction cost estimate does not include interconnection or transmission network upgrade costs.

TURN represents that PG&E used a wind power cost of $46 per megawatt- hour (MWh), based on a CEC staff report issued in August 2003 (August report), escalated through 2013. TURN represents that a report adopted by the CEC and issued in November 2003 (November report) shows levelized costs for wind power, without the federal production tax credit, of $41-49 per MWh in 2005 and $33-36 per MWh in 2010. TURN states that with the tax credit, the costs would be $18-22 per MWh in 2010. Based on this information, TURN recommends that PG&E should be required to recalculate the cost-effectiveness of the SGRP using the November report, and to provide an analysis to demonstrate a reasonable level of wind power in the replacement portfolio. MFP concurs.

The November report states that the numbers referred to by TURN were prepared by a consultant, and are only suggestive because actual prices will vary due to circumstances applicable to individual generation plants. While the

November report refers to the August report, it does not state that it supersedes the August report. The November report also states that its price estimates do not include transmission costs. In addition, since wind power is an intermittent source, additional expenditures would be necessary to achieve the same level of dependable capacity as other alternatives such as combined cycle generation. For these reasons, we find PG&E's use of the wind power costs based on the August report to be reasonable.

MFP contends that PG&E did not consider energy efficiency options in its cost-effectiveness analysis. It notes that Decision (D.) 04-09-060 required applications that present projections of supply-side resource needs to reflect the energy savings goals adopted therein. MFP recommends that PG&E be required to recalculate its cost-effectiveness analysis using the energy efficiency goals and levelized cost estimates adopted in D.04-09-060.

In D.04-09-060, we adopted energy efficiency savings goals for PG&E for 2004-2013, subject to periodic revision. These goals are intended to address incremental energy needs. We also required utilities, in any applications or other filings which present projections of supply-side resource needs, pipeline or transmission needs, proposals for new facilities or otherwise utilize projections of energy demand, to demonstrate that such filings are fully consistent with the Commission's adopted energy savings goals. This application was filed long before D.04-09-060 was adopted, and does not address incremental energy needs. In addition, the adopted goals only run through 2013. Therefore, we will not adopt MFP's recommendation. However, we do not intend by this decision to reduce those goals in any way.

I. Degradation and Plugging Assumptions

ORA states that the Commission should consider how wide the variation in PG&E's degradation scenarios is, and whether deferring the SGRP is reasonable. MFP recommends that, since the need for the SGRP depends on tube degradation rates, the Commission should require PG&E to revise its tube degradation assumptions in its model to reflect the tube inspections taking place in the October-November 2004 refueling outage of Unit 2, the results of which will be available in the first quarter of 2005.

No party has asserted that the tubes in the heat exchangers are not degrading. The record demonstrates that Unit 1 has a 2% chance of reaching the end of its license life, and Unit 2 has a 6% chance. This assumes that the NRC raises the plugging limits and revises the repair criteria as requested by PG&E. If approval is not granted, the chances diminish further. Delaying the SGRP would incur costs to keep the original steam generators in operation that are better spent on the SGRP if it is to be performed. In addition, delay options are influenced by the fact that the Diablo SGRP must be coordinated with the SONGS SGRP that is scheduled to follow it. For the above reasons, ORA's recommendation for consideration of a delay is not reasonable.

The record in this proceeding demonstrates that if the original steam generators are not replaced Diablo will be shut down before the end of its license lives. MFP has not demonstrated that consideration of additional test results for one unit would materially affect the degradation rate. However, we see no reason not to consider the results of the most recent tube inspections, and will do so as soon as they are available. In the interim, since the results are not currently available, we will consider possible results of decreased degradation rates in our cost-benefit calculations, in order to determine whether the SGRP will likely be cost-effective over the range of possible results.[19]

J. Recovery of Capital Costs in the Event of an Early Shutdown

TURN points out that an assumption underlying PG&E's cost-effectiveness calculation is that if Diablo were to shut down at any time, the undepreciated plant balance in ratebase would be fully recovered from ratepayers. TURN asserts that in D.85-08-046, the Commission concluded that the early shutdown of Humboldt Bay Unit 3 (Humboldt), a nuclear power plant, resulted in investment that was no longer used and useful and, therefore, excluded the undepreciated plant costs from ratebase. PG&E was allowed to recover plant costs, but was not allowed to earn a return on the unrecovered amount. TURN also points out that in D.92-08-036, the Commission adopted a settlement regarding the early shutdown of SONGS Unit 1 that allowed SCE to recover its remaining investment, but only allowed a return on the unrecovered amount equal to the embedded cost of debt. As a result, TURN recommends that PG&E be required to run its cost-effectiveness model assuming the treatments adopted in D.92-08-036 and D.85-08-046. ORA and MFP support the use of the regulatory treatments of unrecovered net plant costs, adopted in the above decisions, in the event of an early shutdown. Aglet believes, that recovery of net

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[19] Increased degradation rates will increase the cost-effectiveness of the SGRP. Decreased degradation rates will decrease the cost-effectiveness of the SGRP. Therefore, we will consider the effects of possible decreased degradation rates in our cost-effectiveness analysis.

plant costs in the event of an early shutdown is not assured. It states that the Commission has no firm policy on this matter, and that full recovery is unlikely.

In D.03-12-035, the Commission approved a modified settlement agreement with PG&E that provided that the Utility Retained Generation (URG) rate base established by D.02-04-016 is deemed just and reasonable and not subject to modification, adjustment or reduction other than through normal depreciation.[20] PG&E later signed the modified settlement agreement. The URG rate base adopted in D.02-04-016 included the rate base amount for Diablo as of December 31, 2000.[21] Thus the Commission is precluded from reducing the undepreciated rate base, as of December 31, 2000, for Diablo in the event that Diablo shuts down before the end of its license lives. Only the capital additions that went into ratebase after December 31, 2000, would be subject to the recommendation of TURN, ORA, and MFP.

In D.85-08-046, the Commission addressed the recovery of the remaining undepreciated plant investment in Humboldt that was shut down before the end of its license life. The Commission allowed a four-year amortization of the remaining unrecovered plant investment without a return on the unamortized balance during the amortization period.

In D.92-08-036, the Commission addressed the recovery of remaining undepreciated plant investment for SONGS Unit 1, which was shut down before the end of its license life. The Commission adopted a settlement that allowed a four-year amortization of the remaining unrecovered plant investment. It also

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[20] Paragraph 2f of the modified settlement agreement.

[21] D.02-04-016, mimeo., p. 21.

allowed a return equal to the embedded cost of debt on the unamortized balance during the amortization period. Since this decision adopted a settlement, it did not set a precedent.

It is possible that, in the event of an early shut down, the undepreciated plant balance may be amortized over a four-year period with a reduced or no return on the unamortized balance. However, we normally base depreciation rates on the remaining life of the asset being depreciated. Therefore, it is also possible that depreciation rates for Diablo, in the absence of the SGRP, would be increased based on the shorter expected life. If that was done, the remaining undepreciated capital costs associated with Diablo would be fully recovered over its remaining life with a return earned on the undepreciated balance. At this time, it is premature to make these determinations. Therefore, we will calculate the cost-effectiveness of the SGRP without explicitly assuming a limitation on capital recovery if the SGRP is not performed.

K. Discount Rate

PG&E uses an 8.6% discount rate in its cost-effectiveness calculations that would correspond to a weighted cost of capital of 10.44%. ORA represents that utilities normally use their authorized cost of capital as the discount rate. Aglet states that PG&E's discount rate is based on a simplified capital structure (60% debt and 40% equity) and an assumed 15% return on equity. Aglet contends that PG&E has not justified its simplified capital structure or return on equity.

The parties have mentioned two discount rate calculation methodologies; PG&E's method, and the use of the authorized cost of capital. In D.04-12-047, PG&E's cost of capital was set at 8.53% for 2004, and 8.77% for 2005, which are very close to PG&E's discount rate. Therefore, setting the discount rate at PG&E's authorized cost of capital would result in little change in the discount rate. Applying PG&E's methodology to its authorized cost of capital would yield a 2004 discount rate of 7.37%, and a 2005 discount rate of 7.63%, both of which are lower than PG&E's discount rate. Since most of the SGRP costs occur early on, and most of the benefits occur later, the use of a higher discount rate would make the SGRP less cost-effective. Depending on which methodology is used, a discount rate based on D.04-12-047 would be approximately equal to or less than the 8.6% discount rate used by PG&E. Use of a discount rate less the 8.6% would increase the cost-effectiveness of the SGRP. For the above reasons, we find PG&E's use of an 8.6% discount rate reasonable.

L. License Recapture

TURN represents that PG&E's cost-effectiveness analysis fails to consider the possibility that the NRC will not grant the license recapture requested by PG&E, and thus not extend the Unit 1 license life as assumed by PG&E.

In its cost-effectiveness analysis, PG&E assumed that there is an 80% probability of license recapture for Unit 1. This was based on past NRC approvals of requests to allow the license life to run from the date of the initial full power operating license. In the case of Unit 1, the license life now runs from the date of the low power testing period, approximately three years before the date of the initial full power operating license. PG&E's assumption of an 80% probability of recapture recognizes that there is a chance it will not be granted, and we have no reason to believe that the assigned probability is unreasonable. Therefore, we believe this matter was reasonably addressed by PG&E.

M. The Risk of a Nuclear Accident and the Resulting Shared Costs

TURN represents that PG&E's cost-effectiveness analysis fails to consider the risk of a nuclear accident and the resulting shared costs.

PG&E and all other operators of nuclear generating stations are required to carry insurance for public liability claims as a result of a nuclear accident. In addition, PG&E is required to participate in a loss-sharing program among utilities that own nuclear reactors. Under this program, if a nuclear incident occurs at Diablo or any other nuclear generating station, PG&E may be responsible for up to $201.2 million, with payments limited to $20 million per year until PG&E has paid its full share. If Diablo were to shut down, this liability would not automatically cease. PG&E would have to apply to the NRC to reduce or eliminate its participation in the loss-sharing program. A consequence of any reduction or elimination of its participation in the loss-sharing program would be a corresponding loss of liability protection. There have been no assessments under the loss-sharing program, and the record does not indicate that such an assessment is likely.

The reasonableness of seeking NRC approval to reduce or eliminate participation in the loss-sharing program is a function of the amount of spent fuel and radioactive materials on site. The record does not indicate that such a reduction or elimination would be reasonable given the corresponding reduction in liability protection. In addition, it could take several years to obtain such approval if it was to be requested. Therefore, we see no reason to assume that forgoing the SGRP would result in any significant reduction of PG&E's liability under the loss-sharing program.

VII. Westinghouse Suit

TURN and ORA allege that PG&E should have filed suit against Westinghouse regarding the original steam generators. Aglet states that PG&E has not demonstrated that its failure to file a suit was reasonable. TURN and ORA also state that an award from such a suit should be imputed in setting the allowable costs to be recovered for the SGRP. Specifically, TURN recommends a disallowance of $56-70 million.

TURN's witness Schlissel stated that, by the late 1970s and early 1980s there was substantial publicly available evidence that the steam generators of the type provided by Westinghouse to Diablo would experience significant degradation and incur substantial costs for maintenance, repairs and possibly replacement before the end of their projected service lives. He stated that a number of utilities with similar Westinghouse steam generators filed suit against Westinghouse concerning such problems in the late 1970s through the early 1990s. He also represented that Westinghouse prevailed in the two suits that went to hearing, and the rest were settled. The settlements, however, were confidential. For these reasons, TURN alleges that PG&E should have filed suit against Westinghouse.

Let us assume that TURN's contention that PG&E could and should have known that it had a basis for filing suit in the late 1970s at the earliest, and the early 1990s at the latest is correct. Given that the statute of limitations for filing such a suit is four years, and that PG&E does not have a tolling agreement with Westinghouse extending the statute of limitations, PG&E is barred at this time from filing such a suit. Therefore, the question of whether PG&E should be ordered to file such a suit is moot.

The issue of whether PG&E should have filed a suit against Westinghouse is related to the design of the original steam generators which, in turn, is related to the reasonableness of the cost of the original steam generators. Therefore, if PG&E had filed and won a suit against Westinghouse, the appropriate result would have been a reduction in the rate base attributable to the original steam generators. Therefore, if we were to find that PG&E should have sued Westinghouse, and would have won or received a settlement, the appropriate result would be a reduction in the rate base attributable to original steam generators.

In D.03-12-035, the Commission approved a modified settlement agreement with PG&E that provided, among other things, that the URG rate base established by D.02-04-016 shall be deemed just and reasonable and not subject to modification, adjustment or reduction other than through normal depreciation.[22] The URG rate base adopted in D.02-04-016 included the rate base amount for Diablo as of December 31, 2000, a portion of which is attributable to the original steam generators.[23] Therefore, the Commission would be precluded from making an adjustment to the rate base for the original steam generators, if it was to find that PG&E should have filed suit against Westinghouse, and would have won or received a settlement from Westinghouse.

There is no basis in the record for assuming, and no party has represented, that if PG&E had filed and won a suit against Westinghouse, the original stream generators would have been replaced. As a result, SGRP would not have been

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[22] Paragraph 2f of the modified settlement agreement.

[23] D.02-04-016, mimeo., p. 21.

avoided. Therefore, such a suit would not affect the need for, or the cost of, the SGRP. As a result, an adjustment to the cost of the SGRP to reflect a suit against Westinghouse would be an inappropriate attempt to circumvent the modified settlement agreement. For these reasons, we will not adopt TURN and ORA's recommendations.

VIII. TURN's Cost-Effectiveness Modeling

TURN performed its own cost-effectiveness modeling of Diablo with and without the SGRP. It used mostly PG&E's assumptions, with the exceptions of O&M costs, capacity factors, the timing of plant closure, and the possibility of a one-year outage. No adjustments were made for replacement energy costs, and the regulatory treatment of post-shutdown unrecovered plant investments.

Nineteen scenarios were run. The SGRP was cost-effective in twelve, and not in seven. TURN's analysis showed the benefits of the SGRP to be questionable if Diablo closes prior to the end of its license life, assuming the SGRP is performed, or under a combination of low capacity factors, high O&M costs, or if Diablo were to operate past 2017 without the SGRP. Based on these results, TURN recommends that PG&E be required to run its model with the adjustments it recommends, and assign wider ranges of variability to the capacity factor, O&M costs, capital additions, and the potential for an extended outage. MFP supports the use of TURN's model.

TURN's model yields results generally similar to PG&E's model when the same or similar inputs are used. Therefore, TURN's model tends to support the validity of PG&E's model. TURN's scenarios were intended to analyze the sensitivity of the cost-effectiveness of the SGRP to various input assumptions. Since TURN did not assess the probability of any particular scenario, its calculations are of limited use in assessing the most likely cost-effectiveness outcome of the SGRP.

IX. ORA's Cost-Effectiveness Modeling

ORA supports its cost-effectiveness modeling that concludes that the NPV of the SGRP is approximately $1.1 billion. MFP supports the use of ORA's model.

ORA's model yields results generally similar to PG&E's model when the same or similar inputs are used. Therefore, it tends to support the validity of PG&E's model.

X. Cost-Effectiveness Conclusion

As discussed above, we have adopted the following changes to PG&E's modeling assumptions to be used in our cost-effectiveness calculations:

- SGRP cost of $706 million (base case), and $815 million cap.
- Base capital additions of $87 million for 2016 and after.
- 4.5% O&M escalation rate after 2011.
- September 5, 2003 and April 19, 2004, NYMEX closing prices for gas.
- 30-year facility life for combined cycle generation.

We first change the combined cycle facility life to 30 years. With this change, market prices are lower than combined cycle generation or combined cycle generation with 10% wind. Therefore, we will use market prices in our cost-effectiveness calculations.

PG&E performed steam generator tube inspections during the October-November 2004 refueling outage of Unit 2. We do not have those results at this time, and the results of the tube inspections during the Unit 1 refueling outage in early 2004 were not included in the record.[24] Therefore, we will include consideration of the possibility that the results of the inspections will indicate that the most probable date for Unit 2 to go out of service without the SGRP is one refueling cycle later (referred to as “1 unit refueling outage” in the table below). We will also consider the possibility that the most probable date for both units to go out of service without the SGRP is one refueling cycle later (referred to as “2 unit refueling outage” in the table below).[25]

The following table shows the NPVs, in 2003 dollars, of five scenarios illustrating the results of our cost-effectiveness analysis. A negative NPV indicates that the costs of the SGRP exceed the benefits. The term “High Gas“ refers to replacement electricity costs based on the September 5, 2003 NYMEX closing prices for gas. The term “Low Gas“ refers to replacement electricity costs based on the April 19, 2004 NYMEX closing prices for gas. The base case (first scenario) uses the above modeling assumptions and a $706 million SGRP cost. Subsequent scenarios incorporate additional assumptions. Each scenario is shown using the 90.6% capacity factor used by PG&E in its application, as well as an 85% and an 80% capacity factor.

[24] We will incorporate the results of these two refueling outages in the final decision in this proceeding.

[25] Note that one unit going out of service two refueling cycles later would have an adverse effect on the cost-effectiveness of the SGRP equal to or less than two units going out of service one refueling cycle later, due to the time value of money.

Table of Results

Scenario	Assumptions	Capacity factor[26]	Low Gas ($ millions)	High Gas ($ millions)
1	Base	90.6%	522	804
		85%	313	578
		80%	129	378
2	Base +1 unit refueling outage	90.6%	429	687
		85%	226	468
		80%	47	275
3	Base +1 unit refueling outage	90.6%	333	591
	+$815 million SGRP cost	85%	130	372
		80%	-49	179
4	Base +1 unit refueling outage	90.6%	194	439
	+$815 million SGRP cost	85%	-1	229
	+1-year outage[27]	80%	-172	45
5	Base +2 unit refueling outage	90.6%	217	450
	+$815 million SGRP cost	85%	21	240
		80%	-152	54

[26] Reducing the capacity factor reduces the replacement energy costs because Diablo is generating less energy that needs to be replaced.

[27] Before 2015, at least one unit would still be running if the SGRP is not performed. Therefore, a one-year outage of one unit in 2015 could occur whether the SGRP is performed or not. As a result, a one-year outage in 2015 was assumed. A one-year outage occurring after 2015 would have a lesser effect on cost-effectiveness because of the time value of money.

We have no reason to believe that a one-year outage of one unit is likely. In addition, we have no reason to believe that the tube inspections during the 2004 refueling outages will extend the most probable date for one unit to go out of service without the SGRP by more than one refueling cycle, or for both units by one refueling cycle. Therefore, we believe the third scenario is the most probable. Under this scenario, the SGRP will be cost-effective, even at the low gas price and the $815 million SGRP cost, as long as the capacity factor remains above approximately 82%.

Although we do not believe it likely, if we add a one-year outage in 2015 to the third scenario, the SGRP remains cost-effective at the low gas price and the $815 million SGRP cost as long as the capacity factor remains above approximately 85%, as shown in the fourth scenario.

We have no reason to believe that the tube inspections during the 2004 refueling outages will extend the most probable date for both units to go out of service without the SGRP by two refueling cycles. In that case, however, the SGRP will still be cost-effective, even at the low gas price and the $815 million SGRP cost, as long as the capacity factor remains above approximately 85%, as shown in the fifth scenario.

The above analysis assumes that, if the SGRP is not performed, there would be generation facilities ready and waiting to provide replacement power. If the SGRP is not performed, it would not be known for certain when either Diablo unit would shut down until it is relatively imminent. We expect that investors would be reluctant to build replacement power plants given this uncertainty. Therefore, it is possible that replacement power would not be available when needed, or that the cost would be high. In addition, large generating facilities of any kind, including any necessary fuel transportation facilities and electric transmission facilities, cannot be built overnight, especially given the need to obtain financing, an appropriate site, and the necessary regulatory approvals. For these reasons, the assumption that there would be generation facilities ready and waiting to provide replacement power is optimistic, and likely understates the SGRP's cost-effectiveness.

Additional benefits that derive from the SGRP are the increased likelihood that Diablo will remain in operation as a reliable energy source, reduced air pollution compared to fossil generation, reduced dependence on fossil fuel, and diversity of electricity resources. These unquantified benefits increase the cost-effectiveness of the SGRP.

Based on the above, we preliminarily determine that the SGRP will be cost-effective.

XI. Commission Legal Authority to Approve Rate Recovery of SGRP Costs

Pub. Util. Code § 463 provides that, for the purpose of establishing rates, the Commission shall disallow unreasonable expenditures relating to the planning, construction or operation of utility plant costing more than $50 million.[28] The SGRP costs are related to operation of Diablo.

Section 463.5 provides that the Commission is not required to undertake a reasonableness review of recorded costs of an item of utility plant costing more than $50 million where the Commission has established an estimate of the reasonable costs. However, establishment of an estimate of the reasonable costs

[28] All section references are to the Public Utilities Code unless otherwise indicated.

does not limit or restrict the Commission's discretion in determining the reasonableness of actual costs in subsequent proceedings.

Pursuant to the § 463.5, the Commission will not be required to conduct a reasonableness review of recorded SGRP costs if it establishes an estimate of the reasonable costs of the SGRP herein. However, it may conduct an after-the-fact reasonableness review if it chooses to do so.

XII. Reasonableness Review

PG&E requests authority to recover the costs, up to $706 million without further reasonableness review, and to recover recorded costs in excess of that amount if the Commission determines such additional costs to be prudent and reasonable. PG&E represents that its proposal is consistent with the treatment given to power purchase contracts by § 454.5. PG&E contends that the legislative intent of § 454.5 is to provide utilities and their investors with greater certainty of cost recovery.

TURN states that § 454.5 applies to power purchase contracts, subject to a number of conditions, and does not apply to the SGRP because it is not part of an approved procurement plan. TURN further represents that procurement plans are subject to a public solicitation, with the bids reviewed by a review group, and with the list of evaluated bids submitted to the Commission as part of a request for approval. TURN states that this process was not followed for the SGRP, and the spirit of § 454.5 should not be applied to it.

TURN argues that PG&E's contention, that § 463.5 allows the Commission to avoid an after-the-fact reasonableness review if an estimate of reasonable costs has been adopted in advance, does not prohibit the Commission from doing so. TURN recommends that the Commission should conduct a reasonableness review regardless of what the actual costs turn out to be, in order to provide

PG&E with an incentive to minimize project costs. TURN also contends that PG&E's proposal to review only costs in excess of its estimate is unworkable because there is no practical way to differentiate costs that are over PG&E's overall cost estimate from those that are below it. ORA recommends that the Commission should not pre-approve PG&E's cost estimate because PG&E's estimate of procurement costs was low, the contingency amount for installation costs was reduced to only 2%, and the 20% contingency in the owner's costs is unsupported. Aglet argues that PG&E's proposal to forego a reasonableness review, if SGRP costs are less than or equal to $706 million, shifts the risks of SGRP costs to ratepayers without a corresponding benefit.

Under PG&E's proposal, if the costs exceed $706 million, the additional costs would be subject to a reasonableness review. To examine this recommendation, assume that the actual costs are one dollar over the $706 million limit, and we want to review it for reasonableness. Before we can assess the reasonableness of the expenditure of that dollar, we have to identify what it was spent on. Therein lies the problem.

A project of this magnitude will have hundreds, and possibly thousands of components that are performed over the life of the SGRP. Some of them will cost more than anticipated, and some will cost less. The total project cost is the sum of the costs of these components. To the extent that the $706 million limit is exceeded, the amount over the limit will be the sum of the excess costs of the components that exceeded the estimated costs, less the sum of the cost reductions due to components that cost less than anticipated. Therefore, any costs over the limit will be a net result of the individual costs of the components. It thus appears unlikely that any costs exceeding the limit will be due to a single component. To complicate matters further, PG&E's estimate is not broken down to a fine level of detailed cost components, and the estimated cost includes significant contingencies. This is to be expected since this is early in the project. However, the result is that a reasonableness review of costs over the limit will likely necessitate a review of most, if not all, of the project costs.

A traditional after-the-fact reasonableness review looks at the decisions and resulting expenditures that were made over the life of the project and assesses their reasonableness. Reasonable costs are those resulting from reasonable decisions made over the life of the project by a person with the appropriate education, training and experience based on information that could and should have been available and considered at the time. A project could be reasonable at the start, and become unreasonable to continue later on. Unreasonable costs could be incurred even though the SGRP itself is reasonable. What we have analyzed herein is whether the project appears reasonable at this time based on the information available at this time. We are dealing with estimated costs rather than recorded costs. Therefore, if the SGRP is completed for $706 million or less, the recorded costs are not necessarily reasonable. Likewise, a higher cost is not necessarily unreasonable.

Based on the above, if SGRP costs do not exceed $706 million, we do not intend at this time to require a reasonableness review. However, if the project costs exceed $706 million, or the Commission later finds that it has reason to believe the project costs may be unreasonable regardless of the amount, the entire project cost will be subject to a reasonableness review. The SGRP includes Unit 1 and Unit 2. Some costs will be attributable to both units. Therefore, to avoid issues related to allocation of costs between the units, we will determine whether a reasonableness review is needed after the SGRP is complete for both units.

XIII. Aglet Proposal of Guaranteed Savings.

Aglet proposes that, in lieu of a reasonableness review, PG&E should provide guaranteed ratepayer savings of $600 million over the life of the plant. Aglet states that its proposal would offset the uncertainties of whether the project would be cost-effective. Under the proposal, this guarantee of savings would be accomplished by a comparison each year of the actual costs with an estimate of the costs that would have been incurred during the year if the SGRP had not been performed. The ratepayers would receive a payment of the difference if the estimated savings are not at the required level. In any year where the estimated savings exceed the required level, PG&E could recapture a portion of any previous payments. Aglet recommends that implementation details should be determined in a workshop. TURN generally supports this proposal as an alternative to implementing its recommendations regarding the cost-effectiveness analysis. It recommends that the Commission should conduct a separate phase of this proceeding to address how the proposal would be implemented. ORA recommends consideration of Aglet's proposal.

PG&E opposes Aglet's proposal. It states that it is unfair in that PG&E's shareholders could incur losses while ratepayers were receiving benefits. For example, if the benefits were $300 million, PG&E would be required to provide another $300 million to ratepayers even though the SGRP is cost-effective. In addition, there would be uncertainty as to the amount PG&E would have to provide, if any, until 2025. PG&E asserts that this raises accounting issues, and could lead to concern in the investment community. In addition, the benefit would have to be calculated each year based on an estimate of what would have happened if the SGRP had not been performed, since there will be no way to tell what actually would have happened. SCE's concerns regarding the proposal are essentially the same as PG&E's.

As discussed earlier in this decision, we have found that the likely net benefits of the SGRP are substantially less than PG&E's forecast. We are not granting PG&E a blanket exemption from a reasonableness review if the costs do not exceed $706 million, and are imposing a cap. In addition, Aglet's proposal would have to be based on an estimate of the costs that would result if the SGRP was not performed. For these reasons, we will not adopt Aglet's proposal.

XIV. Ratemaking Treatment

PG&E proposes that the Commission:

1. Adopt $706 million as a reasonable and prudent cost for replacement of the steam generators;[29]

2. Determine that actual costs equal to or less than $706 million will be placed in ratebase and fully recoverable in rates;

3. Authorize PG&E to seek recovery in rates of any amounts above $706 million, subject to an after-the-fact reasonableness review of the additional costs;

4. Authorize PG&E to record the revenue requirement associated with plant additions for each unit equal to or less than $706 million ($380 million for Unit 1 and $326 million for Unit 2) in the UGBA as of the date of operation of each unit;

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[29] The adjustment for actual inflation and cost of capital would be calculated by utilizing the same models and inputs that were used by PG&E to generate the $706 million estimate, with changes made only to reflect the actual inflation rates and costs of capital. No other changes would be made.

5. Authorize PG&E to include the revenue requirement associated with each unit in rates on January 1 of the year following commercial operation of each unit;

6. Authorize PG&E to record in the UGBA the revenue requirement, if any, associated with plant additions above $706 million as of the date of operation of each unit. PG&E would be at risk for these revenue requirements, and would only be allowed to include them in rates if such costs were ultimately found to be reasonable and prudent by the Commission; and

7. Approve modifications to the UGBA to allow for the recording of the above revenue requirements.

PG&E's first three proposals have been addressed previously, and will not be repeated here.

Once the SGRP has been completed for each unit, and the unit is back in service, there is no reason to preclude PG&E from having the opportunity to earn a return on its investment. Therefore, we intend to allow PG&E to record in the UGBA the revenue requirement associated with plant additions up to the cap as of the date of operation of each unit. We also intend to allow PG&E to include the revenue requirement associated with each unit in rates, up to $380 million for Unit 1 and $326 million for Unit 2, on January 1 of the year following commercial operation of each unit.[30] The rate increase would be subject to refund. We will require PG&E to request authority to implement the above rate increase for each unit by advice letter. When the SGRP is complete for both units, PG&E will be

[30] These amounts are based of PG&E's request for $706 million.

required to file an application to include the costs in ratebase. If a reasonableness review is to be performed, it will be done as part of that application.

ORA recommends that the revenue requirement be phased in over three years to avoid an unacceptable increase in rates. PG&E disagrees and represents that the rate increase, based on $706 million, would amount to less than 2%. Since the record does not demonstrate that a significant rate increase would occur, we see no need to require a phase in. However, since circumstances may change, we will not preclude the possibility of a phase in.

XV. Affirmation of Previous ALJ Rulings

On August 12, 2004, PG&E filed motions to strike the pre-filed testimonies of Jay Namson and Gordon Thompson on behalf of MFP. It also filed a motion to strike the testimony of Gary Ackerman on behalf of Western Power Trading Forum (WPTF). By a ruling dated August 31, 2004, the ALJ granted the motions to strike the testimonies of Namson and Ackerman, and denied the motion to strike Thompson's testimony.

Namson's testimony argued that a seismic retrofit of Diablo may be necessary to accommodate large reverse or thrust fault earthquakes, and that PG&E should be ordered to analyze the costs of such a retrofit for consideration in this proceeding. Namson effectively asked that this proceeding be suspended while his recommended seismic review is conducted. According to Namson, such an analysis would be an extensive undertaking. PG&E argued that Namson's testimony should be stricken because seismic issues are not within the Commission's jurisdiction. It also represented that the testimony is speculative and irrelevant.

Imposition of seismic requirements for Diablo is not within the Commission's jurisdiction. Therefore, the Commission does not have the authority to order any changes to the plant if such a review found that any changes were needed. The only way a seismic retrofit will be performed, if one is needed, is if the NRC orders it. Nothing in Namson's testimony suggested that the NRC is likely to order such a study, much less require a retrofit.

Namson's testimony included no estimate of: (1) the probability that such a study would be required by the NRC, (2) the probability that a study would recommend a seismic retrofit, (3) the probability that the NRC would require a retrofit if the study recommended one, (4) the cost of the retrofit, (5) when the retrofit would be performed, and (6) whether the retrofit would be required even if the SGRP were not performed. As a result, Namson's testimony did not specifically address the cost-effectiveness of the SGRP, the need for the SGRP, or ratemaking issues. Therefore, it was beyond the scope of this proceeding. As a result, we affirm the ALJ's ruling to strike Namson's testimony. We note that the ALJ's ruling, while it struck Namson's testimony, did not preclude seismic issues from consideration in this proceeding.

Ackerman's testimony argued that PG&E should be ordered to issue a request for proposals (RFP) for alternatives to the SGRP, and that the need for the SGRP should be evaluated considering the results of the RFP. PG&E countered that the testimony is beyond the scope of this proceeding.

Ackerman's testimony made no offer of proof as to what results its proposal would yield. WPTF or its members could have made unsolicited proposals. In addition, WPTF could have evaluated PG&E's estimates of replacement power costs, or made its own estimates of replacement power costs. However, WPTF chose not to do so.

Ackerman's testimony did not address any costs or benefits. Therefore, it did not address the cost-effectiveness of the SGRP, the need for the SGRP, or ratemaking issues. It also did not address issues in connection with the CEQA review. Therefore, Ackerman's testimony was beyond the scope of this proceeding. As a result, we affirm the ALJ's ruling to strike Ackerman's testimony. We note that the ALJ's ruling did not preclude WPTF from presenting testimony regarding alternate proposals to the SGRP.

On August 12, 2004, PG&E filed a motion to strike the pre-filed testimony of Christopher J. Mayer on behalf of the Modesto Irrigation District. Mayer's testimony requested that the Commission exclude municipal departing load customers who have already departed PG&E's distribution service, or who depart prior to successful commercial operation of the first set of replacement steam generators, from liability for any increased nuclear decommissioning revenue requirements attributable to either replacement or attempted replacement of the steam generators and any related extension of Diablo operations facilitated by replacement of the steam generators. Nuclear decommissioning cost revenue requirements, and the allocation to rates thereof, are not within the scope of this proceeding. Therefore, by a ruling dated September 2, 2004, the ALJ granted the motion to strike. We affirm the ALJ's ruling.

On August 23, 2004, PG&E filed a motion for a protective order for materials related to the issue of whether it should have sued, or should sue, Westinghouse regarding the original steam generators, and contract pricing related to the replacement steam generators. On October 13, 2004, the ALJ issued a ruling granting the motion because failure to do so could jeopardize the ability of PG&E to pursue a suit if so ordered, and to negotiate the lowest reasonable price for contracts related to the SGRP, which could result in higher costs to ratepayers. We affirm the ALJ's ruling.

XVI. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Rules of Practice and Procedure. Comments were filed on ____________________, and reply comments were filed on ________________.

XVII. Assignment of Proceeding

Geoffrey F. Brown is the Assigned Commissioner and Jeffrey P. O'Donnell is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The SGRP is needed if Diablo is to continue operation throughout the remainder of its license lives.

2. If the SGRP is to go forward, a delay would result in more monies being spent on the original steam generators, without a corresponding decrease in the cost of the SGRP, and there would be an increased risk of a forced outage.

3. The record does not indicate the probability that the end of the current statutory prohibition on customers leaving bundled service would lead to the reduction of bundled loads served by PG&E, when the reduction would occur, or the amount of the reduction.

4. Since the load would still have to be served, it does not follow that the demand for electricity would be reduced, or that Diablo would not be needed as a result of the end of the current statutory prohibition on customers leaving bundled service.

5. There is no reason to adjust the cost-effectiveness analysis to consider the effect of the end of the current statutory prohibition on customers leaving bundled service, and no basis for determining what adjustment to make.

6. It is reasonable to assume that capital costs and O&M costs are related to Diablo's performance as measured by its capacity factors because capital and O&M costs are incurred in order to keep Diablo in operation.

7. A low capacity factor could result in increased capital or O&M expenditures to correct any plant problems that led to the low capacity factor.

8. Capital additions or additional O&M could be implemented to avoid an outage or decrease in the capacity factor.

9. There are other factors which may influence capacity factors such as regulatory requirements and plant design.

10. TURN and ORA's calculations appear to yield generally similar results to those generated by PG&E's model when similar inputs are used.

11. PG&E's $706 million estimate did not include the $50 million in decommissioning costs due to the SGRP, but PG&E did include these costs in the cost-benefit calculation.

12. PG&E originally estimated that it would cost $182 million for the procurement contract, $339 million for the installation contract, and $185 million for owner's costs, for a total of $706 million.

13. PG&E has signed a procurement contract for $209.3 million, or approximately 15% more than its estimate.

14. Since PG&E reduced the contingency amount for the installation contract to offset the increased procurement contract costs, the updated SGRP cost estimate is $209.3 for the procurement contract, $311.7 million for the installation contract, and $185 million for owner's costs, for a total of $706 million.

15. The installation contract will be a time and materials contract rather than a fixed-cost contract.

16. Installation contract costs could be more than PG&E estimates, even if the bid it ultimately adopts is the same as the cost it estimates, if more time and/or materials are necessary to complete the project.

17. Owner's costs will be dependent to some degree on the actual costs incurred pursuant to the installation contract.

18. The SGRP could ultimately cost more than $706 million.

19. Use of $815 million as a cap would provide PG&E with some incentive to control costs, while recognizing that costs could be higher than PG&E's estimate.

20. Since the $815 million cap would be adjusted for actual inflation and cost of capital, two significant cost drivers, imposition of such a cap would not put PG&E unduly at risk.

21. A cap would limit ratepayers' exposure to cost overruns, and, to some degree, help ensure that the SGRP is cost-effective.

22. Inclusion of a higher AFUDC rate resulting from a higher cost of capital will result in a higher project cost that would tend to make the SGRP appear less cost-effective, resulting in a more conservative cost-effectiveness analysis.

23. For 2012 through 2024, PG&E escalated its 2011 O&M estimate by 2.5% for inflation, and added in costs related to planned refueling outages.

24. It is not clear from the record that PG&E's estimate of O&M costs is wrong by a specific amount, and there could be unexpected O&M costs in the future.

25. In its cost-effectiveness analysis, PG&E assumed a base level of capital additions, excluding the SGRP, of $24 million based on the average capital additions from 1997-2002.

26. Since PG&E assumed that all major capital additions necessary to operate Diablo until the end of its license lives, if the SGRP is performed, will be

completed by 2015, the only capital additions in its forecast after 2015 are the base capital additions.

27. It is reasonable to assume that there will be plant additions in the future that are not known at present.

28. PG&E's estimated annual capital additions through 2015 are in excess of $87 million.

29. Since PG&E's major capital additions are intended to reduce uncertainty to a substantial degree, it does not follow that PG&E's forecast of major capital additions translates to greater uncertainty as MFP appears to imply by its proposal to increase capital additions by an additional $88 million based on PG&E's forecast of major capital additions.

30. The contract for the low-pressure turbine rotor replacement project was signed in 2002, is scheduled for completion in 2005-6, and is expected to add 40 MW to Diablo's capacity.

31. The low-pressure turbine rotor replacement project is not related to the SGRP.

32. There is no reason to believe that the low-pressure turbine rotor replacement project would be cost-effective to cancel it at this time, or that the project is not needed.

33. MFP's first scenario, which assumes continued operation more than three years after enhanced security requirements are put into effect, corresponds to both the case where the SGRP is performed, and to the case where the SGRP is not performed, unless it is known at the time the requirements are put into effect that neither Diablo unit will continue in operation for more than three years.

34. Given the uncertainty as to when Diablo will shut down if the SGRP is not performed, MFP's first scenario appears to be the most likely scenario both with and without the SGRP.

35. MFP's second scenario, which has both Diablo units permanently shutting down when the enhanced security requirements are put into effect, is unlikely because it would probably be cost-effective to implement security requirements even if only one unit has a few years of life remaining.

36. MFP's third scenario, which assumes that the NRC would exempt Diablo from some of the new security requirements because it will not continue in operation for more than three years, is unlikely because it is uncertain when either of the Diablo units will shut down without the SGRP.

37. If, as MFP appears to believe, enhanced security requirements will be imposed within the next few years, the only effect on the cost-effectiveness analysis would be that the reduction in the increased O&M from $54.5 million to $11 million due to shutting Diablo down would occur at a later date.

38. There is no basis in the record for estimating the probability of the occurrence of future increased security requirements or their timing.

39. It is uncertain that lesser additional security requirements would be imposed if Diablo is shut down at the time of imposition.

40. Based on MFP's representations most, if not all, of any new security requirements would be imposed on Diablo with or without the SGRP.

41. The costs estimated by MFP are illustrative examples rather than estimates based on known requirements.

42. The possibility of future increased security requirements supports our conclusion that some increase in future capital additions and O&M expenses above the amount forecast by PG&E is appropriate.

43. In April 2004, PG&E was granted a permit by San Luis Obispo County to construct an ISFSI for spent nuclear fuel at Diablo. A condition of the permit is that PG&E must update its LTSP to incorporate data developed since the LTSP was created in 1988.

44. If the ISFSI is not approved or is delayed, Diablo could be forced to shut down in 2006 because it will not have sufficient storage for its spent fuel.

45. Neither San Luis Obispo County or the CCC have the authority to require a change to Diablo's seismic design criteria; that authority lies with the NRC.

46. The record contains no estimate of the probability that Diablo's seismic design criteria will be revised, when the revision will be imposed, whether plant modifications will be necessary as a result, or what the costs of such modifications will be.

47. There is no basis in the record for assessing the impact on the cost-effectiveness analysis of a possible revision to Diablo's seismic design criteria.

48. The possibility of future revisions to Diablo's seismic design criteria supports the conclusion that some increase in future capital additions and O&M expenses above the amount forecast by PG&E is appropriate.

49. It is by no means clear that a forced shutdown will occur in 2006.

50. If a forced shutdown were to occur in 2006, the SGRP could be stopped if necessary, and cancellation costs addressed as appropriate.

51. Since a forced shutdown in 2006 would occur before the SGRP, it would have no effect on the cost-effectiveness analysis of the SGRP.

52. TURN's analysis of plant outages does not address the causes of the outages, Diablo's similarity to the plants that experienced the outages, Diablo's vulnerability to such outages, or the degree to which PG&E has taken or plans to take actions to avoid them.

53. The probability of a 12-month outage after the SGRP is completed is dependent to a substantial degree upon the efforts of PG&E to maintain and operate Diablo.

54. The record does not demonstrate that PG&E has not or will not take action to properly maintain and operate Diablo.

55. The record does not demonstrate that PG&E has failed to comply with regulatory requirements for continued operation.

56. There is no reason to believe a 12-month outage after the SGRP is completed is likely.

57. The possibility that a 12-month outage after the SGRP is completed could occur supports our conclusion that some increase in future capital additions and O&M expenses above the amount forecast by PG&E is appropriate.

58. PG&E's estimated future capacity factors for Diablo, assuming the SGRP is performed, are 94.67% between refueling outages, and 90.6% including refueling outages.

59. The record does not demonstrate that PG&E has not or will not take actions to prevent outages and keep Diablo operating at full capacity.

60. There is no reason to believe that a capacity factor below PG&E's estimate is likely.

61. A reduction in the capacity factor due to an unexpected outage would not likely be a routine event affecting the capacity factor for both units for the entire life of the plant.

62. The gas prices forecast by PG&E for this proceeding were its expected annual burner tip gas prices based on the September 5, 2003, NYMEX closing price of forward contracts.

63. In A.04-04-003, PG&E's 2004 LTRP, it forecast gas prices based on the April 19, 2004 NYMEX closing price.

64. Neither the NYMEX closing prices for September 2003 nor April 19, 2004 are necessarily better for estimating gas prices between now and 2025.

65. The CEC's November report states that the numbers referred to by TURN were prepared by a consultant, and are only suggestive because actual prices will vary due to circumstances applicable to individual generation plants.

66. While the CEC's November report refers to the CEC's August report, it does not state that it supersedes the August report.

67. The CEC's November report states that its price estimates do not include transmission costs.

68. Since wind power is an intermittent source, additional expenditures would be necessary to achieve the same level of dependable capacity as other alternatives such as combined cycle generation.

69. D.04-09-060 adopted energy efficiency savings goals for PG&E for 2004-2013, subject to periodic revision, that are intended to address incremental energy needs.

70. D.04-09-060 required utilities, in any applications or other filings that present projections of supply-side resource needs, pipeline or transmission needs, propose new facilities or otherwise utilize projections of energy demand, to demonstrate that such filings are fully consistent with the Commission's adopted energy savings goals.

71. This application was filed long before D.04-09-060 was adopted, and does not address incremental energy needs.

72. The goals adopted in D.04-09-060 only run through 2013.

73. Delaying the SGRP would result in costs to keep the original steam generators in operation that are better spent on the SGRP if it is to be performed.

74. PG&E's cost-effectiveness analysis assumes that if Diablo were to shut down at any time, the undepreciated plant balance in ratebase would be fully recovered from ratepayers.

75. In D.03-12-035, the Commission approved a modified settlement agreement with PG&E that provided that the URG rate base established by D.02-04-016 shall be deemed just and reasonable and not subject to modification, adjustment or reduction other than through normal depreciation.

76. PG&E signed the modified settlement agreement approved by D.03-12-035.

77. The URG rate base adopted in D.02-04-016 included the rate base amount for Diablo as of December 31, 2000.

78. In D.92-08-036, the Commission adopted a settlement that allowed a four-year amortization of the remaining unrecovered plant investment in SONGS Unit 1, and allowed a return equal to the embedded cost of debt on the unamortized balance during the amortization period.

79. Since D.92-08-036 adopted a settlement, it did not set a precedent.

80. In D.85-08-046, the Commission allowed a four-year amortization of the remaining unrecovered plant investment in Humboldt, without a return on the unamortized balance during the amortization period.

81. It is possible that, in the event of an early shut down, the undepreciated plant balance may be amortized over a four-year period with a reduced or no return on the unamortized balance.

82. Since the Commission normally bases depreciation rates on the remaining life of the asset being depreciated, it is possible that depreciation rates for Diablo,

in the absence of the SGRP, would be increased based on the shorter expected life resulting in the remaining undepreciated capital costs associated with Diablo being fully recovered over its remaining life with a return earned on the undepreciated balance.

83. A discount rate based on D.04-12-047 would be approximately equal to or less than the 8.6% discount rate used by PG&E.

84. PG&E's assumption of an 80% probability of license recapture for Unit 1 recognizes that there is a chance it will not be granted, and the Commission has no reason to believe that the assigned probability is unreasonable.

85. PG&E and all other operators of nuclear generating stations are required to carry insurance for public liability claims as a result of a nuclear accident.

86. PG&E is required to participate in a loss-sharing program among utilities that own nuclear reactors. Under the loss-sharing program, if a nuclear incident occurs at Diablo or any other nuclear generating station, PG&E may be responsible for up to $201.2 million, with payments limited to $20 million per year until PG&E has paid its full share.

87. PG&E would have to apply to the NRC to reduce or eliminate its participation in the loss-sharing program.

88. There have been no assessments under the loss-sharing program, and the record does not indicate that such an assessment is likely.

89. The record does not indicate that a reduction or elimination of PG&E's participation in the loss-sharing program would be reasonable given the corresponding reduction in liability protection.

90. There is no reason to assume that foregoing the SGRP would result in any significant reduction of PG&E's liability under the loss-sharing program.

91. The record does not demonstrate that PG&E has a tolling agreement with Westinghouse extending the statute of limitations for filing a suit.

92. Assuming that PG&E could and should have known that it had a basis for filing suit in the late 1970s at the earliest, and the early 1990s at the latest, and that the statute of limitations for filing such a suit is four years, PG&E is barred at this time from filing such a suit.

93. The question of whether PG&E should be ordered to file such a suit is moot.

94. The issue of whether PG&E should have filed a suit against Westinghouse is related to the design of the original steam generators which, in turn, is related to the reasonableness of the cost of the original steam generators.

95. If the Commission were to find, in this proceeding, that PG&E should have sued Westinghouse, and would have won or received a settlement, the appropriate result would be a reduction in the rate base attributable to original steam generators.

96. The URG rate base adopted in D.02-04-016 included the rate base amount for Diablo as of December 31, 2000, a portion of which is attributable to the original steam generators.

97. Since TURN's cost-effectiveness model yields results generally similar to PG&E's model when the same or similar inputs are used, it tends to support the validity of PG&E's model.

98. Since TURN's scenarios were intended to analyze the sensitivity of the cost-effectiveness of the SGRP to various input assumptions, and did not assess the probability of any particular scenario, they are of limited use in assessing the most likely cost-effectiveness outcome of the SGRP.

99. Since ORA's cost-effectiveness model yields results generally similar to PG&E's model when the same or similar inputs are used, it tends to support the validity of PG&E's model.

100. Market prices are lower than combined cycle generation, or combined cycle generation with 10% wind, when a 30-year combined cycle facility life is used.

101. The Commission does not have the results of the tube inspections that took place in the October-November 2004 refueling outage of Unit 2 at this time, and the results of the inspections of Unit 1 during the refueling outage in early 2004 are not in the record.

102. One unit going out of service two refueling cycles later if the SGRP is not performed would have an adverse effect on the cost-effectiveness of the SGRP equal to or less than two units going out of service two refueling cycles later due to the time value of money.

103. There is no reason to believe that a one-year outage of one unit is likely.

104. There is no reason to believe that the tube inspections during the 2004 refueling outages will extend the most probable date for one unit to go out of service without the SGRP by more than one refueling cycle.

105. The SGRP will be cost-effective, assuming the most probable date for one unit to go out of service without the SGRP is extended by one refueling cycle, the low gas price and the $815 million SGRP cost, as long as the capacity factor remains above approximately 86%.

106. Assuming the most probable date for one unit to go out of service without the SGRP is extended by one refueling cycle, the low gas price, the $815 million SGRP cost, and a one-year outage in 2015, the SGRP remains cost-effective as long as the capacity factor remains at about 90.6%.

107. Assuming that the tube inspections during the 2004 refueling outages extend the most probable date for both units to go out of service without the SGRP by two refueling cycles, the SGRP will be cost effective at the low gas price, and the $815 million SGRP cost as long as the capacity factor remains above 85%.

108. The Commission's cost-effectiveness analysis assumes that if the SGRP was not performed, there would be generation facilities ready and waiting to provide replacement power, which is optimistic, and may understate the SGRP's cost-effectiveness, given the fact that it would not be known for certain when either Diablo unit would shut down until it is imminent.

109. Large generating facilities of any kind, including any necessary fuel transportation facilities and electric transmission facilities, cannot be built overnight, especially given the need to obtain financing, an appropriate site, and the necessary regulatory approvals.

110. Additional unquantified benefits that derive from the SGRP are the likelihood that Diablo will remain in operation as a reliable energy source, reduced air pollution compared to fossil generation, reduced dependence on fossil fuel, and diversity of electricity resources.

111. The SGRP costs are related to the operation of Diablo.

112. To the extent that the SGRP costs more than $706 million, the amount over $706 million will be the sum of the excess costs of the components that exceeded the estimated costs, less the sum of the cost reductions due to components that cost less than anticipated.

113. Any costs over $706 million will be a net result of the individual costs of the components.

114. It is unlikely that any costs exceeding $706 million will be due to a single component.

115. PG&E's estimate is not broken down to a fine level of detailed cost components, and the estimated cost includes significant contingencies.

116. A reasonableness review of costs over $706 million will likely necessitate a review of most, if not all, of the project costs.

117. Once the SGRP has been completed for each unit, and the unit is back in service, there is no reason to preclude PG&E from having the opportunity to earn a return on its investment.

118. It is possible that a different ratemaking treatment may be imposed when the advice letters are addressed.

119. Since the record does not demonstrate that a significant rate increase would occur due to the SGRP, there is no need to require a phase in of the rate increase.

120. By a ruling dated August 31, 2004, the ALJ granted PG&E's motions to strike the pre-filed testimonies of Namson and Ackerman.

121. Namson's testimony effectively asked that this proceeding be suspended while a recommended seismic review is conducted.

122. Namson's testimony included no estimate of: (1) the probability that such a study would be required by the NRC, (2) the probability that a study, whether ordered by the Commission or the NRC, would recommend a seismic retrofit, (3) the probability that the NRC would require a retrofit if the study recommended one, (4) the cost of the retrofit, (5) when the retrofit would be performed, and (6) whether the retrofit would be required even if the SGRP were not performed.

123. Since Namson's testimony did not specifically address the cost-effectiveness of the SGRP, the need for the SGRP, or ratemaking issues, it was beyond the scope of this proceeding.

124. The ALJ's ruling striking Namson's testimony did not remove seismic issues from consideration in this proceeding.

125. Ackerman's testimony was effectively asking that this proceeding be suspended until its recommended RFP process is completed at some unspecified time in the future.

126. Ackerman's testimony made no offer of proof as to what results its proposal would yield.

127. WPTF or its members could have made unsolicited proposals, evaluated PG&E's estimates of replacement power costs, or made its own estimates of replacement power costs, but it chose not to do so.

128. Ackerman's testimony did not address any costs or benefits.

129. Since Ackerman's testimony did not address the cost-effectiveness of the SGRP, the need for the SGRP, ratemaking issues, or issues in connection with the CEQA review, it was beyond the scope of this proceeding.

130. The ALJ's ruling striking Ackerman's testimony did not preclude WPTF from presenting testimony regarding alternate proposals to the SGRP.

131. On September 2, 2004, the ALJ issued a ruling granting PG&E's motion to strike Mayer's pre-filed testimony.

132. Since nuclear decommissioning cost revenue requirements, and the allocation to rates thereof, are not within the scope of this proceeding, Mayer's testimony was beyond the scope of his proceeding.

133. On October 13, 2004, the ALJ issued a ruling granting PG&E's motion for a protective order because failure to do so could jeopardize the ability of PG&E to

pursue a suit if so ordered, and to negotiate the lowest reasonable price for contracts related to the SGRP, which could result in higher costs to ratepayers.

Conclusions of Law

1. If the SGRP is approved, it should be performed according to PG&E's proposed schedule.

2. Since no decision has been reached in A.04-02-026, it is premature to consider whether the risks of capacity shortages, when compared to the costs of project delays, warrant a change in the steam generator replacement schedule for Diablo at this time.

3. It is not unreasonable that PG&E's model does not incorporate a mathematical formula directly linking capital costs, O&M costs and capacity factors.

4. PG&E's model is appropriate for use in this proceeding.

5. PG&E's SGRP cost estimate of $706 million is reasonable.

6. The Commission should increase the installation contract cost and owner's costs to obtain a possible total SGRP cost of $815 million for use in analyzing the cost-effectiveness of the SGRP.

7. The Commission should adopt $815 million as a cap.

8. Utilizing PG&E's AFUDC rate in evaluating this application will not adversely affect ratepayers.

9. The Commission should use a 4.5% O&M cost escalation rate after 2011.

10. Base capital additions should be increased to $87 million for the years after 2015.

11. MFP's proposal to increase capital additions by an additional $88 million based on PG&E's forecast of major capital additions should not be adopted.

12. The low-pressure turbine rotor replacement project costs should not be included in the cost-effectiveness evaluation of the SGRP.

13. MFP's cost estimates for enhanced security at Diablo should not be adopted.

14. The possibility of a forced shutdown in 2006 should not be included in the cost-effectiveness analysis of the SGRP.

15. For the reasons put forth by TURN, the Commission should use a 30-year facility life for combined cycle generation in its cost-effectiveness analysis.

16. PG&E's use of the wind power costs based on the August report is reasonable.

17. MFP's recommendation to recalculate the cost-effectiveness analysis using the energy efficiency goals and costs adopted in D.04-09-060 should not be adopted.

18. ORA's recommendation for consideration of a delay is not reasonable and should be adopted.

19. Additional tube degradation test results from refueling outages during 2004 should be considered when they are available.

20. The Commission is precluded from reducing the undepreciated rate base, as of December 31, 2000, for Diablo in the event that the SGRP is not implemented, and Diablo shuts down before the end of its license lives.

21. It is premature to determine the ratemaking treatment of Diablo in the event of an early shutdown.

22. The Commission should calculate the cost-effectiveness of the SGRP without explicitly assuming a limitation on capital recovery if the SGRP is not performed.

23. PG&E's use of an 8.6% discount rate is reasonable.

24. PG&E's assumption of an 80% probability of license recapture for Unit 1 is reasonable.

25. The Commission would be precluded from making an adjustment to the rate base for the original steam generators, if it were to find that PG&E should have filed suit against Westinghouse, and would have won or received a settlement from Westinghouse.

26. Since there is no basis in the record for assuming that if PG&E had filed and won a suit against Westinghouse the original stream generators would have been replaced, such a suit would not affect the need for, or the cost of, the SGRP.

27. The Commission should not adopt TURN's recommended disallowance of $56-70 million.

28. The Commission should use market prices in its cost-effectiveness analysis.

29. The Commission should preliminarily determine that the SGRP is cost-effective.

30. Section 463 provides that, for the purpose of establishing rates, the Commission shall disallow unreasonable expenditures relating to the planning, construction or operation of utility plant costing more than $50 million.

31. Section 463.5 provides that the Commission is not required to undertake a reasonableness review of recorded costs of an item of utility plant costing more than $50 million where the Commission has established an estimate of the reasonable costs. However, establishment of reasonable costs does not limit or restrict the Commission's discretion in determining the reasonableness of actual costs in subsequent proceedings.

32. If the SGRP costs do not exceed $706 million, the Commission should not intend at this time to require a reasonableness review.

33. If the SGRP cost exceeds $706 million, or the Commission later finds that it has reason to believe the SGRP cost may be unreasonable regardless of the amount, the entire SGRP cost should be subject to a reasonableness review.

34. In order to avoid issues related to allocation of costs between the units, the Commission should determine whether a reasonableness review is needed after both units are complete.

35. The Commission should not adopt Aglet's proposal for guaranteed savings from the SGRP because: (1) the likely net benefits of the SGRP are substantially less than PG&E's forecast; (2) we are not granting PG&E a blanket exemption from a reasonableness review if the costs do not exceed $706 million; (3) we are imposing a cap; and (4) Aglet's proposal would have to be based on an estimate of the costs that would result if the SGRP was not performed.

36. The Commission should allow PG&E to record in the UGBA the revenue requirement associated with plant additions up to the cap as of the date of operation of each unit.

37. The Commission should allow PG&E to include the revenue requirement associated with each unit in rates, up to $380 million for Unit 1 and $326 million for Unit 2 on January 1 of the year following commercial operation of each unit, subject to refund.

38. PG&E should be required to request authority to implement the rate increase for each unit by advice letter.

39. When the SGRP is complete for both units, PG&E should be required to file an application to include the costs in ratebase. If a reasonableness review is to be performed, it should be done as part of that application.

40. The Commission should not preclude the possibility of a phase in of the SGRP rate increase.

41. Since imposition of seismic requirements for Diablo is not within the Commission's jurisdiction, it does not have the authority to order any changes to Diablo if such a review of seismic requirements found that any changes were needed.

42. The Commission should affirm the ALJ's ruling striking Namson's testimony.

43. The Commission should affirm the ALJ's ruling striking Ackerman's testimony.

44. The Commission should affirm the ALJ's ruling striking Mayer's testimony.

45. The Commission should affirm the ALJ's ruling granting the motion for a protective order.

INTERIM ORDER

IT IS ORDERED that:

1. Our preliminary conclusions regarding this application are as follows:

   - The Steam generator replacement program (SGRP) for Diablo Canyon Power Plant is cost-effective.

   - $706 million, as adjusted for actual inflation and cost of capital, is a reasonable estimate of the SGRP cost.

   - We do not intend to conduct an after-the-fact reasonableness review if the SGRP cost does not exceed $706 million, as adjusted for actual inflation and cost of capital.

- If the SGRP cost exceeds $706 million, as adjusted for actual inflation and cost of capital, or the Commission later finds that it has reason to believe the costs may be unreasonable regardless of the amount, the entire SGRP cost will be subject to a reasonableness review.

- The maximum allowable SGRP cost (cap) is $815 million as adjusted for actual inflation and cost of capital. PG&E will not be allowed to recover SGRP costs in excess of this amount.

- We intend to allow Pacific Gas and Electric Company (PG&E) to record in the Utility Generation Balancing Account (UGBA) the revenue requirement associated with plant additions up to the cap as of the date of operation of each unit.

- We intend to allow PG&E to include the revenue requirement associated with each unit in rates and subject to refund, up to $380 million for Unit 1 and $326 million for Unit 2 on January 1 of the year following commercial operation of each unit. PG&E will be required to file an advice letter to request authority to implement the above rate increase for each unit. The rate increase shall not take effect until and unless the advice letter is approved by the Commission.

- After completion of the SGRP, PG&E will be required to file an application for inclusion of the costs thereof permanently in rates, regardless of whether the costs exceed $706 million. If a reasonableness review is performed, it will be done in connection with the application.

2. We affirm the Administrative Law Judge's rulings discussed herein.

3. By this opinion, we do not approve or disapprove the SGRP, guarantee or approve the recovery of any expenditures related thereto, or dictate the outcome of our environmental review of the SGRP pursuant to the California Environmental Quality Act (CEQA).

4. This proceeding remains open to consider the results of our environmental review of the SGRP pursuant to CEQA, and to make a final determination on the matters for which our preliminary determinations are stated herein.

This order is effective today.

Dated ____________________________, at San Francisco, California.